DIRECT TESTIMONY OF

Dr. Ben Johnson

ON BEHALF OF THE

SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

Before the

PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2018-2-E

Introduction

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida. I am a Consulting Economist and President of Ben Johnson Associates, Inc., a consulting firm that specializes in public utility regulation.

Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?

A. I have been retained by the South Carolina Solar Business Alliance, LLC ("SBA") to assist in preparing and presenting evidence in this proceeding with respect to the Public

Utility Regulatory Policies Act of 1978 ("PURPA"), the avoided costs of South Carolina Electric & Gas ("SCE&G" or "the Company") and proposed changes to Rate PR-2. Members of SBA include Independent Power Producers that sell the output of their facilities to incumbent utilities like Duke Energy and SCE&G in the generation of electricity under PURPA. These firms are planning to invest (or are already in the process of investing) more than $5 Billion in the development of solar generating facilities in the state of South Carolina over the next 3 to 4 years.[1] Depending on the economic success or failure of these initial investments, the extent of future needs for generation, and the state's regulatory and competitive climate, these firms are likely to make additional investments in future years. Needless to say, with billions of investment dollars at stake, the SBA members are vitally interested in the PURPA related issues in this proceeding.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. The earliest case I can recall was Docket No. 77-354-E which was a 1978 case involving Carolina Power & Light Company. I've worked in several other South Carolina proceedings since that time, involving electric, telephone and water utilities. The most recent case was Docket No. 2017-2-E.

Q. CAN YOU PLEASE BRIEFLY DESCRIBE YOUR OTHER QUALIFICATIONS?

1 Allowable Ex Parte Briefing No-2018-5-E, March 14, 2018 Transcript, Page 56.

A. Yes. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics.

I have been actively involved in public utility regulation since 1974. Over the past four decades I've been involved in many different types of regulatory proceedings. This work has encompassed an unusually broad range of issues – from setting the appropriate rate of return, to the appropriate items to allow or disallow in the rate base, to weather normalization adjustments, to integrated resource planning, to the allocation of costs across jurisdictions and customer classes, to in-depth prudence reviews related to two nuclear plants (the South Texas Project, where I worked on behalf of a large group of municipalities, and the Shearon Harris plant, where I worked on behalf of the Public Staff of the North Carolina Public Utilities Commission). I also have extensive experience working in proceedings related to competitive entry into industries that have historically been organized around vertically integrated monopolies, including many different proceedings involving the implementation of PURPA, beginning with Docket No. 14 E-100, Sub 53, a 1986 North Carolina proceeding concerning avoided costs.

All told, I have participated in more than 400 regulatory dockets over the course of my career, and I've provided expert testimony on more than 300 occasions before state and federal courts and utility regulatory commissions in 35 states, two Canadian provinces, and the District of Columbia. Most of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation, but members of my firm and I have worked for other clients, including large industrial customers, non-profit organizations like the AARP, and independent power producers.

Q. HAVE YOU PREPARED AN APPENDIX THAT PROVIDES SOME ADDITIONAL DETAILS CONCERNING YOUR QUALIFICATIONS?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Following this introduction, I first provide some rate comparisons. Second, I discuss various aspects of PURPA from my perspective as an economist. Third, I discuss some methodologies that can be used to estimate avoided costs. Fourth, I discuss the Company's avoided energy costs. Fifth, I discuss the Company's proposed QF related tariff changes, including its proposal to reduce its QF capacity rates to zero, and to reduce solar rates below those paid to non-solar QF's. In this section I note the major changes the Company is proposing to its methods and inputs for calculating avoided cost, which would have the effect of sending less precise price signals to independent power producers and discouraging QF investment. I also explain why stronger, more accurate QF price signals are needed. Sixth, I provide estimates of long run avoided capacity costs which can be useful in setting capacity rates. Finally, I provide my recommendations for what action the Commission should take in this proceeding.

Rate Comparisons

Q. CAN YOU BRIEFLY DESCRIBE THE CURRENT AND PROPOSED RATES PAID TO QUALIFYING FACILITIES?

A. Yes. Under PURPA, electric utilities are required to purchase energy and capacity from certain independent power producers, provided they build and operate relatively small generating plants with a capacity equal to or less than 80 MW, and provided they use certain designated technologies. Firms that meet specific standards set forth in the applicable federal regulations are called Qualified Facilities (QF's), and they are allowed to connect these facilities to the grid, in competition with the generating units in the incumbent utility's rate base.

QF's are paid for the electricity they produce based on negotiated rates, or rates that are set by the state regulatory commission, consistent with regulations established by the Federal Energy Regulatory Commission (FERC). The current SCE&G QF tariffs were approved by the Commission in Docket 2017-2-E on April 19, 2017. The current tariff sets forth a single set of rates applicable to all types of QF's, with variations depending on the timing of when the power is provided by the QF. More specifically, the current (and proposed) SCE&G tariffs provide separate rates for 5 year blocks. The currently approved rates are for the years 2017 – 2021, 2022 – 2026 and 2027 – 2031, while the proposed rates are for the years 2018 – 2022, 2023 – 2027 and 2028 – 2032. This tariff structure apparently gives QF's the option of contracting to sell capacity and energy for up to 15 years, with the QF being paid different rates during each 5 year period.

Under both the current and proposed tariffs, QF's are paid higher rates during the summer, and lower rates during the rest of the year. There is also a difference related to the time when the electricity is injected into the grid, with higher rates paid during on-peak hours and lower rates during off-peak hours and on holidays and weekends.

Unlike the current tariff, the tariff proposed that is being reviewed in this proceeding segregates solar QF's from other power providers, and the SBA members will presumably be paid less for their electricity than the rates that will be paid to other qualified technologies under PURPA, like biomass, wind and hydro.

Q. PRIOR TO RECEIVING THE NEW TARIFF FILING, WHAT CHANGES DID YOU EXPECT TO SEE IN SCE&G'S PROPOSED ENERGY RATES?

A. I expected to see a small degree of upward movement. This follows logically because the energy rates are closely tied to natural gas and fuel prices, and those prices (and projections of future price levels) have not changed greatly over the past year, aside from the impact of another year of inflation. However, I was also expecting an increase in the avoided cost of energy due to the cancellation of the V.C. Summer nuclear units. While the nuclear units were going to be very costly on an "all-in" basis, including the enormous cost of building these units, the units were also expected to be operated at nearly full capacity on a year-round basis, with very low variable costs. This influx of nuclear energy was expected to displace energy produced by coal and natural-gas fired units which have higher variable costs. Once the nuclear units were canceled, the logical consequence would be to reverse (or eliminate) these effects, causing the existing coal and gas units to operate longer hours, along with larger purchased power costs with higher variable costs than the nuclear units. The end result should have been an increase in the QF energy rates. Without the very high capital costs associated with the nuclear units, the net result would likely be lower rates paid by retail customers – despite paying slightly higher rates to QF's.

Q. BEFORE YOU SAW THE NEW TARIFF FILING, WHAT CHANGES WERE YOU EXPECTING TO SEE WITH RESPECT TO QF CAPACITY RATES?

A. I expected to see a significant increase in the Company's QF capacity rate, bringing it close to the QF rates approved by this Commission for Duke Energy Carolinas (1.242 cents per kWh) and Duke Energy Progress (1.321 cents per kWh). This expectation logically followed from the fact that the nuclear units had recently been canceled, and those units were previously expected to meet all of the Company's need for capacity in the near future (and arguably create a degree of excess capacity). It is my understanding that the existence of those units was the primary factor explaining why SCE&G proposed such low capacity rates in Docket No. 2017-2-E (as little as 0.149 cents per kWh).

In the previous fuel case (Docket No. 2017-2-E), the Company essentially argued that the costs of the nuclear units were not avoidable, and that it had contractual commitments to purchase firm power that would meet all of its capacity needs until the nuclear units were scheduled for completion. In effect, the Company contended that it had no ability to "avoid" capacity costs, which seemed to be the primary justification for paying nothing to QF's for their capacity in most years. Once the nuclear units were canceled, this rationale disappeared, and so I expected that applying the same logic, assumptions and methodology would translate into significantly higher capacity rates.

Q. HAVE YOU COMPARED THE QF RATES PROPOSED IN THIS CASE TO ANALOGOUS RATES APPROVED IN THE LAST PROCEEDING?

A. Yes. I compared the rates on a composite or weighted average basis, as they apply to a typical solar facility. More specifically, I looked at the rates that are currently applicable during each hour of each day of the year, and applied them to the volume of energy which can reasonably be expected from a typical QF solar facility, to estimate the total payments that would be received by the QF. The total payments were then divided by the total kWh which were expected to be produced by the QF, in order to calculate an overall composite rate per kWh. This procedure took into account how the Summer and Non-Summer seasons are defined, as well as how the peak and non-peak time periods are defined in the current tariff. Most of the energy produced by solar QF's qualifies for the on-peak rate – with the exception of weekends, when the lower off-peak rate applies regardless of the time of day.

The results of this comparison are shown below for the first five year time period:

Difference in SCE&G Rates paid to QF's:
Current 2017-2021 versus Proposed 2018-2022 (prices per kWh)

	Energy	Capacity	Total
Current Tariff	3.253 cents	0.153 cents	3.406 cents
Proposed Tariff	2.853 cents	0.000 cents	2.853 cents
Difference	-0.400 cents	-0.153 cents	-0.553 cents
Percent Difference	-12.3%	-100.0 %	-16.2 %

This table shows a similar comparison for the next five year period:

Difference in SCE&G Rates paid to QF's:
Current 2022-2026 versus Proposed 2023-2027 (prices per kWh)

	Energy	Capacity	Total
Current Tariff	3.054 cents	0.153 cents	3.207 cents
Proposed Tariff	2.994 cents	0.000 cents	2.994 cents
Difference	-0.060 cents	-0.153 cents	-0.213 cents
Percent Difference	-2.0%	-100.0 %	-6.6 %

This table shows a similar comparison for the final five year period:

Difference in SCE&G Rates paid to QF's:
Current 2022-2026 versus Proposed 2023-2027 (prices per kWh)

	Energy	Capacity	Total
Current Tariff	3.383 cents	0.153 cents	3.536 cents
Proposed Tariff	3.414 cents	0.000 cents	3.414 cents
Difference	+ 0.031 cents	-0.153 cents	-0.122 cents
Percent Difference	+ 0.9%	-100.0 %	-3.5 %

In all years, SCE&G is proposing to reduce payments to QF's. The largest percentage reduction occurs in the initial five year period (which happens to be the one with the greatest negative impact on the Net Present Value of a QF investment). In contrast, if the Company had simply updated its input assumptions to reflect changes in fuel prices and economic conditions, taking into account the cancellation of the nuclear units and applying the methodology previously approved by the Commission in the same manner as it had in the past, SCE&G would have calculated higher QF rates – not lower rates.

PURPA

Q. CAN YOU PLEASE EXPLAIN YOUR UNDERSTANDING OF THE FEDERAL STANDARDS WHICH APPLY TO QF RATES?

A. Yes. As I alluded to previously, in 1978, Congress established a special class of generating facilities known as "Qualifying Facilities."[2] Under PURPA, electric utilities are required to purchase electrical energy from Qualifying Facilities ("QF's") at rates which must not discriminate against the firms that operate these facilities. More specifically, PURPA requires the Federal Energy Regulatory Commission ("FERC") to prescribe rules necessary to "encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity."[3] State commissions have an important role in implementing PURPA, together with FERC and the courts. Questions about the actual avoided-cost determinations are litigated before the state commissions or the state courts with applicable jurisdiction for non-regulated utilities. Questions regarding whether a method of avoided-cost

2 16 U.S.C. § 824a-3.

3 16 U.S.C. § 824a-3(a).

determination is consistent with PURPA and FERC implementation rules are litigated before FERC or an applicable federal court.[4]

State commissions have been provided with extensive guidance for how they are to carry out their responsibilities, both in the text of the underlying statute, and in rules adopted by FERC which were subsequently upheld by the United States Supreme Court.[5] For instance, rates for purchases from QF's ("QF rates") must: a) be just and reasonable to the electric consumers of the electric utility and in the public interest; b) not discriminate against qualifying cogenerators or qualifying small power producers; and c) cannot exceed "the incremental cost to the electric utility of alternative electric energy."[6]

While I am not an attorney, it is my understanding as an economist that under PURPA the Commission is expected to (1) require utilities to purchase energy and capacity from QF's on terms consistent with all applicable FERC regulations; (2) treat avoided costs as the pricing floor for those purchases; (3) enforce the legal right for QF's to sell power to utilities on either an as-available basis, or pursuant to a "Legally Enforceable Obligation" at the QF's option; (4) enforce the legal right for QF's to sell power to utilities pursuant

4 PURPA Title II Compliance Manual, Page 15. The PURPA Title II Compliance Manual was jointly published by the American Public Power Association (APPA), Edison Electric Institute (EEI), National Association of Regulatory Commissioners (NARUC) and National Rural Electric Cooperative Association (NRECA) on March 2014, with the intended purpose of being used as an aid to state commissions and utilities as they deal with issues related to PURPA.

5 *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 103 S. Ct. 1921 (1983).

6 16 U.S.C. § 824a-3(a).

to long-term contracts; (5) ensure utilities provide nondiscriminatory interconnection and/or transmission service to QF's that they sell power to QF's on request.

Q. CAN YOU EXPLAIN THE "INDIFFERENCE" STANDARD AND THE "AVOIDED COST" CONCEPT?

A. Yes. As the FERC has stated on several occasions, the intention of Congress in enacting PURPA "was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly encouraged alternatives" of PURPA.[7] As explained more recently by the North Carolina Utilities Commission, "the goal is to make ratepayers indifferent between purchases of QF power versus construction and rate basing of utility-built resources."[8] Although PURPA is designed to encourage QF development, it does not accomplish this by subsidizing QF's, or by requiring customers to pay more for their power. To the contrary, if PURPA is correctly implemented, ratepayers are "held harmless," leaving them indifferent to whether they receive power from a QF or from new generating units added to the utility's rate base.

FERC recently confirmed that ratepayers should be "financially indifferent" when QF rates are appropriately set, and it went further by rejecting arguments that financial indifference must be narrowly defined, to exclude consideration of "societal and

[7] *Southern Cal. Edison, San Diego Gas & Elec.*, 71 FERC ¶ 61,269 at p. 62,080 (1995).

[8] North Carolina Utilities Commission, December 31, 2014 Order Setting Avoided Cost Input Parameters, Docket No. E-100, Sub 140, Page 21.

environmental benefits."[9]

The FERC rules implementing PURPA generally require electric utilities to purchase any energy and capacity which is made available to the utility from a Qualifying Facility.[10] Rates for purchases from Qualifying Facilities built after 1978 must be based upon the electric utility's "avoided costs."[11] FERC defines avoided costs as:

> [T]he incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[12]

Among other things, the FERC rules require state commissions, to the extent practicable, to consider these factors when determining avoided costs:

> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> (i) The ability of the utility to dispatch the qualifying facility;
>
> (ii) The expected or demonstrated reliability of the qualifying facility;
>
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

9 FERC, Order Denying Rehearing, Docket No. EL 10-06-002, January 20, 2011, Paragraph 16.

10 18 C.F.R. § 292.303(a).

11 18 C.F.R. § 292.101(b).

12 18 C.F.R. § 292.101(b)(6).

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.[13]

Q. CAN YOU EXPLAIN WHAT INFORMATION IS REQUIRED BY SECTION 292.302(B) OF THE FEDERAL CODE OF REGULATIONS?

A. Yes. Under FERC PURPA regulations, utilities like SCE&G are required not less often than every two years to provide to their state regulatory commission the following information, and to make it available for public inspection:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases

[13] 18 C.F.R. § 292.304(e).

> from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
>
> (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and
>
> (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.[14]

SCE&G generally submits this information to the Commission in June of even-numbered years – most recently in June 2014 and June 2016.

Q. CAN YOU EXPLAIN YOUR UNDERSTANDING OF WHY THIS INFORMATION HAS TO BE PUBLICLY AVAILABLE, WHY THE "INDIFFERENCE" AND "AVOIDED COST" REQUIREMENTS WERE IMPOSED, AND WHAT THESE ASPECTS OF PURPA ACCOMPLISHED?

A. Yes. Looking at the relevant portions of PURPA from my perspective as an economist, it appears to advance at least two distinct goals: First, it encourages expanded use of targeted technologies and energy sources which had been neglected by the electric utility

[14] 18 U.S.C. § 292.302(b).

industry. Second, it encourages investment in small power producers – new firms that enter the market to develop these targeted technologies and energy sources.

With respect to the first goal, PURPA advanced an "all of the above" energy strategy, which was intended to encourage greater energy independence and increased supply diversity in the United States.

The scope of this portion of PURPA was narrowly focused. Utilities were exempted from any requirement to purchase from independent power producers that used the energy sources that had been historically been favored by electric utilities, like coal, residual oil, nuclear and natural gas. Instead, Congress focused on certain unconventional energy sources, like cogeneration, that had not been aggressively pursued by utilities.

Other targeted technologies include electricity produced from biomass and waste, as well as renewable resources like wind, small hydro, solar and geothermal energy. The primary purpose in encouraging investment in these specialized energy sources was similar to the reason why cogeneration was targeted: if PURPA was successful in encouraging new entry, supply diversity would be improved, and the country would reduce its dependence on scarce and nonrenewable resources like coal and oil.

Q. CAN YOU ELABORATE ON THE SECOND GOAL YOU MENTIONED – ENCOURAGING INVESTMENT BY SMALL INDEPENDENT POWER PRODUCERS?

A. Yes. By requiring utilities to purchase from QF's, Congress was not only encouraging diversity of energy supply sources, but it was also pursuing a strategy of encouraging diversification of suppliers of electric power generation. PURPA was adopted at a time when public policy makers were trying to scale back unnecessary regulations, improve regulatory structures, and rely more on competition to advance the public interest – particularly in industries, like the electric power industry, where competition had been effectively suppressed by government policy.

Perhaps the most memorable and visible example of this new approach was the deregulation of airlines which occurred around the same time. In this industry, safety continued to be tightly regulated, but other rules were changed to remove barriers to entry, encourage new airlines to challenge incumbent firms and to deregulate prices, which had previously been tightly controlled. The resulting increase in competition successfully unleashed a tidal wave of innovations, cost cutting, and price reductions.

Although PURPA was not as visible or dramatic, it reflected much the same pro-competitive philosophy underpinning airline deregulation. Congress sought to gain some of the benefits of increased competition without foregoing the benefits of traditional rate base regulation. The idea was to retain existing constraints on monopoly power in retail markets, while introducing new, carefully thought-through constraints on monopsony power in wholesale markets. The key to this strategy was encouraging increased investment and new entry by small, independent power producers, who had the potential to unleash downward pressures on the incumbents' costs and retail prices, without taking the risk of fully deregulating an industry which had many of the characteristics of a natural monopoly.

Thus, it is fair to say that one of the fundamental goals of this portion of PURPA was to encourage, on a narrowly targeted basis, increased competition in the market for electrical generation without jeopardizing continued regulation of other aspects of the industry. The strategy was straightforward: encourage investment in small firms that would use unconventional technologies to produce electricity in competition with the existing, vertically integrated electric utilities.

Q. WHY WAS THIS TYPE OF INVESTMENT ENCOURAGED?

A. Prior to the adoption of PURPA, most electric utilities obtained all, or nearly all, of their power from large centralized generating plants that they owned and constructed themselves, or from similar plants operated by a nearby utility. Congress made a conscious decision in 1978 to deviate from this historical pattern by encouraging investment in small power producers (80 MW or less at any single site) that would be entering the market in competition with the vertically integrated utilities, provided they focused on the targeted technologies. This had the effect of introducing a small degree of competition into the industry, encouraging greater geographic diversity, and encouraging the use of unconventional technologies.

Before PURPA, the monopoly power enjoyed by electric utilities in the transmission and distribution of electricity and the regulatory apparatus designed to constrain that monopoly power combined to discourage competition. This was true even for parts of the electric industry – like generation – which did not seem to exhibit the characteristics of a natural monopoly.

For example, before PURPA, few industrial firms would consider generating their own power, even where this would be economically efficient (e.g. utilizing waste heat from the manufacturing process), because there wasn't a ready market for power produced in excess of the firm's own needs. Practical constraints, as well as legal barriers associated with monopoly regulation, made it difficult or impossible for industrial firms to sell power to anyone other than the local utility, and most utilities weren't interested in buying power from new entrants. Rather, electric utilities generally preferred obtaining power from conventional generating plants – particularly ones they owned and operated themselves.

Before PURPA was adopted, the utility's preference for owning and operating its own generating plants using conventional energy sources nearly always prevailed over what might otherwise have been commercially viable transactions to purchase from independent power producers that would have ultimately benefited the utilities' customers. The utility was largely immune from pressures to pursue unfamiliar technologies or to buy from independent power producers, because it was effectively both a monopolist (single seller) and a monopsonist (single buyer), within its particular service territory.

Thus, for example, unless an industrial firm was willing to pull up stakes and move to another state, it was forced to pay whatever price the utility charged for whatever power it used, and it was forced to accept whatever price (typically much lower) the utility was willing to pay for any extra power the industrial firm produced. Before PURPA, if the gap between the price charged and the price paid seemed unduly large, an industrial firm could in theory complain to the state regulator about the magnitude of the gap, and ask the regulator to require the utility to pay a higher price, but in practice this option was generally too costly and risky to be worth pursuing. Accordingly, before PURPA, most industrial firms ignored the potential for cogeneration, regardless of how attractive the underlying economics might be, rather than risk undertaking an investment that would be subject to the utility's unconstrained monopsony power, or the uncertain outcome of future regulatory decisions.

This problem was not limited to cogeneration by industrial firms – it also affected the viability of investments in power production by small run-of-river hydro plants and other opportunities that existed for generating electrical power on a small scale. The utility was typically the sole buyer of power in the local market, and it controlled interconnection to the power grid, thereby largely determining the viability of small power production by other firms. Absent a well-defined system of constraints on the utility's monopsony power, small power production was an enormously risky proposition that few investors were willing to seriously contemplate.

Q. CAN YOU ELABORATE ON THE DISTINCTION BETWEEN MONOPOLY POWER AND MONOPSONY POWER, AS IT RELATES TO THE HISTORY OF UTILITY REGULATION?

A. Yes. By the early 1900's in most jurisdictions a comprehensive system of regulation to control monopoly power had evolved, which severely limited the ability of electric utilities to impose unreasonable prices, terms, and conditions on their sales transactions with most retail customers. In contrast, prior to the adoption of PURPA, relatively little thought was given to monopsony power, and in most jurisdictions no comparable comprehensive regulatory mechanisms existed to constrain the behavior of electric utilities in their dealings with independent power producers.

As the primary or exclusive potential buyer of electrical energy within their respective market areas, the incumbent electric utilities enjoyed as much "monopsony power" when buying electricity as the "monopoly power" they had when selling energy. Taking advantage of their market power, utilities generally decided to construct, own and operate their own generating units, or to purchase power from neighboring utilities, rather than buying from independent firms.

In general, incumbent utilities prevented, or at least discouraged, competitive entry by other firms, even in situations where those firms had a clear efficiency advantage (e.g. the ability to generate electricity less expensively, by taking advantage of waste heat involved in industrial processes), or they were willing to take greater risks in trying new, less familiar technologies.

The result was that electric utilities prevented the consuming public from realizing the benefits of competition by independent power producers, who could potentially bring down costs and bring long term societal benefits by increasing supply source diversity, experimenting with innovative technologies, reducing costs, increasing efficiency, or accepting lower profit margins.

In sum, the potential benefits from imposing regulatory constraints on monopsony power are conceptually similar to the reasons why the monopoly power of the incumbent utilities have long been constrained. However, the existence of monopsony power, and the benefits from constraining it, have not been as widely understood or effectively dealt with.

Q. CAN YOU EXPLAIN WHY UTILITIES RESIST COMPETITION AND PREFER THEIR OWN GENERATING FACILITIES?

A. There are many factors that help explain why electric utilities have historically resisted competitive entry: (1) There is a natural tendency for utility company management to want to retain maximum direct control over system reliability and other outcomes for which they are ultimately accountable. (2) Management operates within the context of a growth-oriented U.S. corporate culture, which favors expansion of a firm's staff, assets, income, and earnings per share. (3) Management is expected to maximize profits and value for its stockholders, which leads to a strong bias in favor of expanding the rate base, due to the Averch-Johnson effect.[15]

With PURPA, Congress attempted to overcome this resistance by reducing barriers to competitive entry into the electric utility industry without disrupting the more successful aspects of traditional rate base regulation. It did this by providing an overarching federal regulatory structure for implementing state regulatory oversight of transactions between electric utilities and QF's, with a view toward encouraging QF investment.

[15] Named after the authors of a famous article published in 1962 in the American Economic Review, which demonstrated that under typical conditions, rational rate base regulated firms will tend to expand their capital investment beyond the optimal point of maximum economic efficiency. This tendency occurs whenever the allowed rate of return exceeds the utility's actual cost of capital by even a small margin. Theoretically the Averch-Johnson effect could be avoided if the allowed rate of return were set precisely equal to the cost of capital. However, this degree of precision isn't achievable in practice. As well, an allowed return which exceeds a barebones estimate of the cost of capital can be viewed as preferable, since it helps maintain the utility's financial integrity, strengthens its financial ratios, and protects its bond rating.

However, PURPA did not change the attitudes or preferences of the incumbent utilities. These firms continue to prefer owning and operating their own generating resources for perfectly rational reasons. If the benefits of competitive entry are going to fully emerge, it is necessary for state and federal regulators to actively implement the provisions of PURPA in a way that fulfills the goal of encouraging competitive entry, and placing greater reliance on market forces to advance the interests of ratepayers and the public good.

Q. HAVE UTILITIES CONTINUED TO RESIST COMPETITIVE POWER PRODUCTION, DESPITE THE REQUIREMENTS OF PURPA?

A. Yes. In my experience, utility companies have consistently advocated proposals that have tended to discourage QF investment and justified continued expansion of their own rate base instead. While continued resistance to competitive entry is readily predicted and explained as a matter of economic theory, it's important to realize this is not a merely speculative or theoretical concern, but a fundamental aspect of the industry.

It is helpful for regulators to understand and recognize this aspect of the industry in deciding how to interpret and implement the various provisions of PURPA. Succinctly stated, in a typical retail rate proceeding, the utility will often seek rates that are higher than necessary or appropriate, but in a QF rate proceeding the reverse is true: the utility will often seek rates that are lower than necessary or appropriate. The Commission should keep this in mind, and try to strike an appropriate balance which serves the long-run best interests of the consuming public in South Carolina.

The historical record is filled with evidence that confirms the industry's preference for low QF rates, its resistance to QF investment, and its preference for putting generating units into their rate base rather than purchasing power from independent power producers. For example, the industry opposed FERC's rules implementing PURPA, arguing that it was inappropriate to require them to pay QF rates that were equal to their full avoided cost. Utilities fought this battle all the way to the U.S. Supreme Court, which unanimously rejected their arguments, concluding that FERC had not acted arbitrarily or capriciously in requiring utilities to buy QF energy at rates equal to full avoided cost.[16] The Court recognized this would not directly provide any rate savings to consumers, but it accepted FERC's reasoning that it was more important to provide a significant incentive for the development of cogeneration and small power production, and that ratepayers and the nation as a whole will benefit from decreased reliance on scarce fossil fuels and increased efficiency. Since that time, utilities have generally been more circumspect in their efforts to discourage QF development in preference for investing in their own facilities, but they have continued to do so.

[16] *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 103 S.Ct. 1921 (1983)

Q. CAN YOU EXPLAIN HOW UTILITIES DISCOURAGE INVESTMENT BY INDEPENDENT POWER PRODUCERS?

A. Yes. For instance, utilities often resist negotiating with independent power producers. Rather than seeking "win-win" solutions, they refuse to co-operate, they are slow to offer information that would be useful in clearing up confusion or resolving disputes and they make it easier for a competitor to walk away than to reach agreement. They can also create unnecessary delays in the contract negotiation and interconnection process, making it more costly and difficult to get a project off the ground. Similarly, utilities often insist on QF contracts with much shorter durations than they themselves use when building and financing projects, or the insist upon contractual terms that they would reject if they were on the other side of the negotiation.

They may also seek to impose terms and conditions that will make it more difficult to obtain financing for QF projects, yet which offer little or no benefit for the retail customers on whose behalf they are procuring power. In order to finance a project, QF's will typically need to have already signed a long-term purchase power agreement at fixed or pre-specified prices. Those prices and other terms of the contract are crucial in determining whether banks and other investors will invest the capital needed to complete a project.

Utilities also tend to develop low estimates of their avoided costs and low estimates of what costs customers will incur if they produce the power, rather than a competitor.

Tellingly, however, they rarely offer to back up the cost estimate for their own generating units with any sort of price guarantee or accept any of the risk of underestimating the costs. There have been many examples where utilities have offered rosy projections of how long it will take, and what it will cost, to build and operate a new generating plant. Once they obtain permission to go forward with the investment, which all but guarantees it will go into rate base, they rarely volunteer details concerning how the investment is turning out in practice. Only in the rare case where extreme schedule delays are experienced, or construction costs vastly exceed the original estimates, does the impact on ratepayers undergo intense scrutiny. More commonly, the gap between the original cost estimate per kWh and the actual costs passed through to customers is not publicly disclosed or thoroughly scrutinized.

All of these problems and risks are alleviated or avoided when the utility obtains power from independent power producers at a guaranteed long-term fixed price. When QF's enter a market pursuant to PURPA, the risks of schedule delays and construction cost over-runs are borne by the competitor. Similarly, when they sign a long-term purchased power agreement ("PPA") at a fixed price, QF's bear all of the risk of future inflation or cost escalations due to changing economic conditions, turmoil in global energy markets, and other unexpected events.

Yet, rather than seeking to encourage competitive risk taking which would benefit their retail customers, utilities prefer to build and operate their own generators. This preference is consistent with economic theory, including the Averch-Johnson effect (which predicts that regulated monopolies will seek to expand the size of their rate base investment beyond the point which is economically optimal from a societal perspective). This preference is not just a matter of theory. It is an empirical fact, clearly revealed by the way incumbent utilities have so consistently implemented the requirements of PURPA using tactics to discourage competitive entry. Specific examples I've observed include:

- Adopting an unduly narrow view of what costs can be avoided;

- Shielding their avoided cost calculations from public disclosure, making it harder for potential market entrants to evaluate the long-term investment risks and prospects in a given state;

- Disclosing few details concerning their input, assumptions and avoided cost calculations in their testimony and exhibits, which makes it harder for regulators to identify flaws in their avoided cost calculations or to draw meaningful comparisons between those calculations and those put forward in testimony in other jurisdictions;

- Using different fuel price forecasts to estimate avoided costs than the ones they use to evaluate and defend investments in their own generating units, with those differences consistently favoring more investment being placed into rate base and less reliance on purchases from independent power producers;

- Putting their own generating units (existing or proposed) at the "front of the line" during the planning process, and treating their own plants as a fixed element of the planning process, regardless of whether other options (like canceling construction or selling the plant) might be better for ratepayers. This has the effect of treating the QF investment as redundant or unnecessary, and biasing the analysis in favor of a larger rate base, even when this is not in the best interest of their retail customers;

- Effectively discriminating against QF's by not providing them with any compensation or credit for shouldering risks that would be borne by their retail customers when they build and operate their own plants;

- Developing QF rates using inconsistent and/or biased assumptions that are skewed against the QF; and

- Resisting proposals to improve the precision and sophistication of the tariff development process, if the effect of those improvements proposals might be to attract more competitive entry, or to encourage more QF investment.

Unfortunately, utilities' QF tariff filings under PURPA don't always receive the same level of scrutiny as their retail tariff filings. There are many possible explanations for this, including the fact that the issues are sometimes unfamiliar, and they arise in the context of highly specialized tariffs which have an immediate, direct effect on very few people.

Q. DO RETAIL CUSTOMERS BENEFIT FROM SETTING QF RATES AT ARTIFICIALLY LOW LEVELS?

A. No. Although low QF rates may be superficially appealing (on the assumption that lower QF rates will translate into lower retail rates through a fuel adjustment and purchased power mechanism), artificially suppressing QF rates does not benefit ratepayers. Any short term benefit from low QF rates is of limited value, because low QF rates discourage QF investment, thereby reducing the amount of energy that the utility will actually obtain at the lower rates. Taken to the extreme, if QF rates are so low that no QF investment occurs, no purchases will be made at the low rates, and there will be no savings available to flow through to retail customers.

Even if some QF developers end up selling some power at an artificially low rate (e.g. they are already committed to their projects before the low rates are established), the potential benefit to retail customers will be limited, because future QF investment will be discouraged and the potential for increased pressure on the utility to operate efficiently will be lost. Instead, customers will be forced to buy more costly power generated by the utility itself. Simply stated, over the long run, retail customers are harmed by low QF rates, because low rates shield utilities from competition, reducing pressures for them to minimize their costs.

Furthermore, low QF rates encourage unnecessary expansion of the regulated rate base, thereby shifting risks onto retail customers that could have been borne by QF investors instead. For example, when generating plants are built by utilities, customers bear nearly all of the risks associated with scheduled delays and construction cost overruns. Absent an extraordinary finding of imprudence, which rarely occurs, all of the risks associated with construction are ultimately borne by ratepayers. Even in cases where a plant is retired early, or construction is never completed, ratepayers will normally shoulder the burden of any resulting stranded costs.

In contrast, when independent power producers build plants, customers are shielded from these risks, because they only pay for power that is actually generated, and the price remains the same regardless of what delays or cost over-runs occur during construction. In sum, it is not in the public interest for the Commission to endorse unrealistically low avoided cost estimates, or to adopt low QF Rates. To the contrary, the public interest is best served by encouraging competition, by accurately and fairly implementing the provisions of PURPA and the associated FERC rules.

Q. ARE YOU ADVOCATING SETTING QF RATES AT THE HIGHEST LEVEL ALLOWABLE UNDER PURPA?

A. No. A middle course is preferable. Retail customers are better served by regulatory decisions that set QF rates away from these extremes, at a point that is closer to, but somewhat below the long run incremental costs that are incurred by utilities when they build and operate their own generating plants. I believe this long-run incremental cost standard is also consistent with the requirements of federal law. It encourages competitive entry by small power producers, without imposing a long-run cost burden on customers, and without subsidizing QF development or running the risk of encouraging economically inefficient levels of QF investment.

Stated a little differently, the public interest is best achieved by establishing rates that leave ratepayers indifferent as to whether energy and capacity is obtained from QF's or from the utility itself under traditional rate base regulation. By setting QF rates equal to the cost of having the utility build and operate its own generating units, PURPA creates a level competitive playing field between utility-owned generation and QF power purchases. This encourages investment by QF developers to the extent they believe they can operate more efficiently or at lower cost, or they are more willing to experiment with new technologies, or they are willing to accept a lower return on their investment than the one paid on comparable investments put into the utility's rate base. This creates healthy competition, which exerts downward pressures on retail rates, pressures the incumbent utilities to minimize their own costs, and benefits retail customers over the long term.

Q. YOU MENTIONED LONG-RUN COSTS AS THE APPROPRIATE STANDARD. WHY SHOULDN'T QF RATES BE EVALUATED STRICTLY ON THE BASIS OF SHORT-RUN ENERGY COST SAVINGS?

A. For one thing, PURPA requires that QFs be given the option of contracting at long-term avoided cost rates, in recognition that long-term price certainty is typically essential to securing investment in QFs, just as it is with investments in utility-owned generation.[17] I also believe that retail customers (and society as a whole) will be best served by making policy decisions primarily on the basis of long-run costs, rather than narrowly focusing on short-run phenomena, like the fuel savings that are achieved when the incumbent utility's generating units are operated less. Furthermore, the goals of PURPA can best be accomplished by taking a long-term view of the choice between QF and utility-provided power. More specifically, I believe the concept of "indifference" and the calculation of avoided costs should primarily be based upon consideration of the full incremental cost of building and operating generating facilities over their entire economic life cycle.

In the electric utility industry, short-run costs are sometimes less than long-run costs, due to lumpiness of capital additions among other factors. However, ratepayer are required to bear the full long-run cost of plants that are put into the rate base. If QF rates only considered a short-run measure of costs, like the variable operating costs incurred when

[17] *Hydrodynamics Inc.*, 146 FERC ¶ 61,193 (Mar. 20, 2014) at P 34; 18 C.F.R. § 292.304(d)(2).

operating the utility's generating plants, while ignoring the other (fixed) costs utilities incur (and customers pay) for these plants over the long run, a severe mismatch occurs, and indifference is not, and cannot be, achieved. Stated another way, using a short-run view of avoided costs that fails to consider the full cost of building and operating new generating plants over their economic life cycle will discriminate against QF's, create a barrier to competitive entry, and discourage QF investment.

Accordingly, it has often been recognized that the appropriate measure of avoided costs is one that is equivalent to the total costs incurred when a utility builds, owns and operates new generating plants over their life cycle. Properly implemented, a long-run measure of costs ensures that QF's receive the same amount for their power as the utilities receive for power produced using their own generating plants – no more and no less.

It should also be noted that QF's typically sign long-term contracts to sell their output at "fixed or pre-specified prices" and this is type of contract is needed for them to obtain debt financing. For logical consistency, long-term contracts generally require the use of "long-term estimates of avoided cost."[18]

[18] Edison Electric Institute, PURPA: Making the Sequel Better than the Original, December 2006, Page 9.

Avoided Cost Methodologies

Q. HOW ARE "AVOIDED COSTS" ESTIMATED?

A. There are three major methods that have been used to develop avoided cost estimates, including (1) the Proxy Unit method (also sometimes referred to as the Proxy Resource or Committed Unit method), (2) the Differential Revenue Requirement (DRR) method, and (3) the Peaker method.[19] The Commission has accepted the use of both the DRR and Peaker methods (SCE&G uses the DRR method and Duke uses the Peaker method) but there is no inherent inconsistency in doing this. To the contrary, all three of these methods are intended to measure the same thing (long run incremental costs), so all three methods can (and should) yield approximately the same total cost per kWh under normal circumstances (assuming each one is properly performed using similar inputs and assumptions).

Q. CAN YOU BRIEFLY EXPLAIN THE PROXY UNIT METHOD?

A. Yes. The Proxy Unit (or Proxy Resource) method is described in the PURPA Title II Compliance Manual as follows:

> This method bases the avoided cost on the cost of the host utility's next planned addition, typically a combined cycle/gas turbine (CCGT) generating unit. This approach essentially assumes that the QF substitutes

[19] PURPA: Making the Sequel Better than the Original, page 9. See also the PURPA Title II Compliance Manual, page 35 and Reviving PURPA's Purpose, Carolyn Elefant, Page 13

for a planned utility generating unit, or what is assumed to be the next generating unit. The proxy unit's estimated fixed cost (annualized over the expected life of the unit) determines the avoided capacity cost and the estimated variable cost sets the avoided energy cost. The type and size of the unit or units is determined in an Integrated Resource Process (IRP) or from the utility's planning process, where the planning process, for regulated utilities, follows a state commission-approved procedure. Because this is a relatively simple method to use, the proxy method is very common, although the results largely depend on the type of unit or units chosen as the proxy.[20]

This methodology has many advantages, including the fact that it is relatively straightforward and easily understood. Its flexibility is also an advantage: It can be implemented using data for a generating unit that is currently under construction, or has recently been constructed by the utility, a unit that has been identified for future construction in the utility's Integrated Resource Plan, a hypothetical or surrogate unit, or some combination or variant of these data sources. Later in my testimony I will be using the Proxy Unit method to provide an independent assessment of SCE&G's avoided costs, for comparison with the Company's proposed QF rates.

Q. ARE YOU ASKING THE COMMISSION TO ADOPT THE PROXY UNIT METHOD IN LIEU OF THE DRR METHOD?

A. No, not at all. All three of these methods are intended to measure the same thing, and the choice of a specific method in a specific context is largely a matter of administrative or calculational convenience. It should not have any significant impact on the conclusions

[20] PURPA Title II Compliance Manual, page 35.

that are reached – assuming consistent assumptions and inputs are used in each instance.

In this instance, it was convenient to use the Proxy Unit method to develop some benchmark cost estimates for presentation to the Commission and to clarify some of the points I make in my testimony. The Proxy Unit method was ideal for this purpose because: (1) it is a relatively straightforward, simple method which is relatively easy to explain, implement and understand; (2) it can be developed using publicly available information, thereby improving transparency and reliability; (3) it offers great flexibility, which made it easier to develop multiple different calculations using a wide variety of different assumptions (e.g. fuel choices and cost scenarios); and (4) it is well suited for consideration of the information that must be provided by utilities pursuant to 18 C.F.R. Section 292.302(b) as I mentioned earlier in my testimony.[21] This is significant, since the FERC rules specifically require state regulators to consider this information in setting avoided-cost based rates, to the extent practicable.[22] Moreover, this avoided cost data is available for many different utilities, potentially facilitating comparisons with data submitted by other utilities. However, none of the conclusions I reach are contingent on the use of the Proxy Unit method, nor am I suggesting the Company, or the Commission,

[21] All of the information submitted by utilities pursuant to this regulation tends to be useful, including the cost of planned capacity additions and firm purchases on the basis of dollars per kilowatt, and the associated costs of each unit, expressed in cents per kilowatt hour. In SCE&G's case, this submission includes the cost of the recently canceled V.C. Summer nuclear generating units, which provides a useful point of reference for comparison with the proposed QF rates.

[22] 18 C.F.R. § 292.304(e).

should switch to the Proxy Unit method.

Q. CAN YOU BRIEFLY EXPLAIN THE DIFFERENTIAL REVENUE REQUIREMENT METHOD?

A. Yes. The DRR method is described in the PURPA Title II Compliance Manual as follows:

> Under a revenue requirement differential method, the system revenue requirement without the QF is subtracted from the system revenue requirement with the QF.[23]

The DRR method, as typically discussed, is a fairly complex approach, requiring the use of two different computer models.

> A planning expansion model is used to develop generation expansion plans both with and without the estimated QF output. The resulting two expansion plans then are used as inputs to a financial planning model that yields the utility's projected revenue requirement both with and without the QF output (assuming that the QF's are a "free" resource). The difference in the present value revenue requirements of these two expansion plans is the avoided revenue requirement made possible by the expected QF output. This avoided revenue requirement includes avoided energy and capacity costs as well as other factors (e.g., taxes)[24]

SCE&G's witness, Dr. Lynch, explains that his avoided energy and capacity cost calculations were developed using a "difference in revenue requirements methodology"[25]

> The base case is defined by SCE&G's existing fleet of generators and

[23] PURPA Title II Compliance Manual, page 35.

[24] PURPA: Making the Sequel Better than the Original, December 2006, Page 11.

[25] Direct Testimony of Joseph M. Lynch, page 4.

> the hourly load profile to be supplied by these generators. The change case is the same as the base case except that the hourly loads are reduced by a 100 MW profile, which is the maximum required by PURPA regulation 18 C.F.R. § 292.302(b)(1) for utilities with systems larger than 1,000 MW of generation such as SCE&G....
>
> The avoided energy cost is simply the difference between the base case costs and the change case costs. The avoided capacity cost is the difference between the incremental capacity costs in both its base resource plan and the change plan.[26]

As is typical of the DRR method, SCE&G compares two different scenarios. Its avoided cost estimates are based on the computed difference between these scenarios. However, the Company's approach is simplified, because it does not develop a comprehensive, detailed analysis of its revenue requirement under any of the scenarios. Instead, it analyzed various different potential generation expansion plans, then it separately analyzed energy costs associated with those expansion plans using the PROSYM model. At no point in its testimony, exhibits or workpapers does the Company pull all of these calculations together in order to show the actual revenue requirement corresponding to various combinations, nor does it demonstrate that the approach it is choosing to model is consistent with minimizing its revenue requirements (or minimizing rates charged its retail customers).

The Company was asked in discovery to produce "[c]opies of all work papers and source documents, utilized or relied upon in formulating SCE&G's request for a new PR-2

[26] *Id.*, pages 4-5.

Rate." In response it provided various workpapers which do not actually compute its rate base or develop its operating expenses, revenues, and miscellaneous sources of income in a manner that is equivalent to the way its revenue requirements would be developed in a retail rate case. Instead, it adopts simplifying assumptions and inputs which, as I will explain later in my testimony, lead me to question the reliability of its calculations.

While the Company used a powerful computer modeling tool (PROSYM) which is capable of analyzing many different scenarios it didn't use the full power of computer modeling to analyze its revenue requirements in full detail. Furthermore, it relied on some assumptions that are completely unrealistic, it adopted some assumptions that are speculative or highly improbable, and it failed to evaluate some important strategies to most effectively deal with the cancellation of the nuclear units, as well as the growth of solar on the Company's system.

All of these problems are important in this case, having a direct impact on the conclusions the Company reached, and the avoided cost calculations it proposes to use for its new QF rates. I will discuss these problems in more detail later.

Q. CAN YOU BRIEFLY EXPLAIN THE PEAKER METHOD?

A. This is the method which Duke has historically used in both South and North Carolina. The Peaker Method is described in the PURPA Title II Compliance Manual as follows:

> Under the peaker method, the value of the QF's capacity is determined by assuming that the QF will be operating as a utility peaking unit. If the utility requires capacity, this method sets the avoided capacity at the lowest-cost capacity option available to the utility, for example, a combustion turbine (CT). Avoided energy cost may be based on the utility's system-wide avoided energy cost, not the peaking unit's energy cost. This requires production cost modeling to determine the system-wide avoided energy cost, which increases the complexity of this method over the "proxy" unit approach.[27]

The Peaker method has at least one significant advantage: it develops energy cost estimates on an hour-by-hour, year-by-year basis. However, some of this advantage can be lost when the calculations are averaged and levelized across broad, potentially arbitrary "Peak" and "Non-Peak" categories and seasons (groups of months). The Peaker Method also has at least one significant disadvantage: it is not especially well-suited to fully utilize the information provided pursuant to 18 C.F.R. Section 292.302(b), particularly with regard to the incremental cost of nuclear and other baseload generating units, since this data isn't used in the Peaker Method.

Q. DO ALL THREE OF THESE METHODS ESTIMATE THE INCREMENTAL COST OF BUILDING AND OPERATING NEW GENERATING FACILITIES OVER THEIR ECONOMIC LIFE CYCLE?

A. They can and they should. Whether or not this is actually accomplished in practice depends on whether they are correctly implemented, with appropriate assumptions and

[27] PURPA Title II Compliance Manual, page 35.

inputs.

It is easiest to see this with the Proxy Unit method, which specifically focuses on the life cycle cost of owning and operating a specific unit. Like any method, the costs that are calculated will vary – particularly on a per kWh basis – depending on the assumptions and inputs which are selected, and how they are used. For instance, if avoided costs are being calculated for use in paying QF's for power that will be generated during many hours of the year, the primary focus should be on a proxy unit that is cost-effective in serving long duration loads, like a Combined Cycle or Nuclear unit. If the analysis were limited to a peaking unit instead, the resulting cost per kWh could be higher than the full life cycle cost of owning and operating a baseload plant, because a combustion turbine has very high fuel costs, which outweigh its low construction costs if power is going to be provided during many hours of a typical day.

In the case of the Differential Revenue Requirement method, the opposite problem can arise, but the outcome will again depend on the inputs and assumptions that are actually used. There is nothing inherently invalid about the DRR method – but the results can easily be skewed against the QF, depending on what inputs and assumptions are used. In particular, with the DRR method it is imperative to show that the revenue requirement is being appropriately minimized in each scenario – consistent with the way retail ratepayers should be protected from monopoly power by ensuring that the revenue requirement used setting retail rates is not excessive or unreasonable.

Under the DRR method, key inputs and assumptions should all be adapted to the circumstances, to ensure that the revenue requirement is minimized under each specific scenario that is considered. For instance, in the "change" scenario which includes a "free" block of 100 MW of power provided by a QF, appropriate inputs and assumptions should be used (or adjusted) to ensure that the full long-run benefit of having this block of power available is taken into account. If inappropriate or overly simplified inputs or assumptions are used, there may appear to be little difference between the two scenarios, and thus the value of the "free" block of power may be underestimated. When the revenue requirements in both scenarios are correctly analyzed, comparing two optimal long-run scenarios in which the revenue requirement is minimized consistent with the circumstances of that scenario, the comparison should reveal the true economic value of the power being provided by the QF. In turn, when this method is implemented correctly, one would expect the final conclusion to be fairly similar to the full cost of building and operating generating units capable of providing the hypothetical "free" block of power.

The Peaker Method will also achieve this benchmark when appropriately implemented, although it isn't intuitively obvious how it can accomplish this, since this method focuses on the capital cost of a peaker (combustion turbine or CT) rather than a base load plant. However, according to the theory underpinning the Peaker Method, assuming appropriate assumptions are used in running the production cost model (e.g. PROSYM), the marginal running costs of the system (output from the model) should exceed the running costs of a new baseload plant by just enough margin to compensate for the added cost of the baseload plant, relative to the cost of a new peaking unit.

> According to the theory underlying the Peaker Method, if the utility's generating system is operating at equilibrium (i.e., at the optimal point), the cost of a peaker (combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost. It will also equal the avoided cost of a baseload plant, despite the fact that the capital costs of a peaker are less than those of a baseload plant. This is because the lower capital costs of the CT are offset by the fuel and other operation and maintenance expenses included in system marginal running costs, which are higher for a peaker than for a new baseload plant. Thus, the summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker.[28]

Although it isn't intuitively obvious, this reasoning is fundamental to the theory underlying the Peaker Method, which assumes combustion turbines with poor heat rates will be operated at the top of the dispatch stack during enough hours of the year to ensure that the difference in fuel costs (e.g. between a new peaking unit and a new nuclear generating unit) will compensate for the additional capital costs of the baseload unit.

Stated another way, the Peaker Method doesn't provide recovery of the high fixed costs of a baseload plant like a Combined Cycle unit or nuclear plant in the avoided capacity cost results. Instead, the capacity costs are limited to those of a CT, while the remainder

[28] North Carolina Utilities Commission, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 100, September 29, 2005, Page 17.

of the fixed costs of owning and operating a baseload plant are supposed to show up in the energy costs. The avoided energy costs are based upon the "top of the stack" (typically, the least fuel-efficient generating unit that is running during any given hour), which are expected to exceed the cost of fuel for baseload units by an amount that should be large enough to recover the portion of the baseload plant investment that exceeds the investment in a peaking unit.

Q. CAN YOU BRIEFLY HIGHLIGHT SOME PRACTICAL ISSUES WITH RESPECT TO PRODUCTION COST MODELS, LIKE PROSYM?

A. Yes. SCE&G relies on computerized production cost modeling to estimate its avoided energy costs on an hour-by-hour, year-by-year basis. The great advantage of these models is that they produce cost estimates in extreme granular detail (literally 8,760 different cost numbers are generated for each year), and they can easily accomplish this level of granular detail for many different scenarios – simply by adjusting the inputs used in running the model for each scenario. For instance, a production cost model can easily develop precise estimates of how costs will be affected during various time periods and seasons, depending on what happens to fuel prices in future years. Similarly, it can provide this sort of highly granular cost information for scenarios reflecting other uncertainties, like the timing of when the V.C. Summer nuclear units were expected to be completed, or how much the Company's energy costs (and retail rates) could be reduced if some of the excess energy that becomes available when these units are finished were to be sold to other utilities.

Unfortunately, the Company did not provide the detailed, hourly PROSYM output with its testimony in this proceeding, nor did it provide this information in response to discovery. Instead, it summarized or aggregated this data across broad on-peak and off-peak time periods. This obscures some of the potential benefits of using PROSYM, which is capable of developing energy costs on a detailed, hour-by-hour, month-by-month, and year-by-year basis. Similarly, the Company didn't take full advantage of PROSYM's inherent "What if" capabilities to provide the Commission and other interested parties with energy cost estimates under multiple different scenarios (e.g. higher or lower fuel prices in future years, or varied rates of growth in solar energy).

This failure to take full advantage of PROSYM's capabilities is not something that can easily be rectified, especially given the time constraints that apply to this proceeding. This problem highlights one of the most significant disadvantages of using a production cost model: they are data-intensive and costly to license. Furthermore, extensive training is required before these models can be operated reliably. Because of these licensing and training barriers, the model effectively becomes a "black box" which cannot easily be penetrated by the Commission, ORS or other parties. Due to licensing and other barriers, other parties cannot readily test or modify the underlying inputs and assumptions that drive the avoided energy cost estimates produced by a model like PROSYM. This is a significant problem, since the inputs largely control the outputs of these types of computer models.

Avoided Energy Costs

Q. HAVE YOU DEVELOPED ESTIMATES OF THE COMPANY'S AVOIDED ENERGY COSTS?

A. Yes. I developed several long-run avoided energy cost estimates using the Proxy Unit method. Some of these estimates are based on a hypothetical nuclear plant, similar to the recently canceled V.C. Summer project, some are based on a hypothetical Combined Cycle plant, and some are based on a hypothetical Combustion Turbine. I also considered several different fuel cost scenarios, as I will explain later in my testimony.

When thinking about energy costs, maintenance, fuel and other operating costs that vary with energy output are what immediately come to mind. However, it's important to note that my energy-related cost estimates also include certain fixed capital-related costs. Dr. Lynch, in his direct testimony on behalf of SCE&G in this proceeding, alluded to this complication, in the context of the requirement under PURPA that QF rates consider both avoided energy costs and avoided capacity costs:

> Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.[29]

[29] Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Page 4 (citing Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies

Ultimately, what is most important is the total price paid to the QF for the energy it provides – including the portion of the price which compensates for variable operating costs avoided, as well as the portion which compensates for the capital-related costs that provide the ability to produce electrical energy. To maintain consistency with the requirements of PURPA, and to draw a meaningful distinction between energy and capacity costs, it's important to realize that the share of total costs that are fixed (capital-related) relative to the share that is variable will depend on the technology that is used to generate the electricity. The costs of producing energy using hydro and nuclear involves mostly fixed costs, while technologies that burn coal or gas necessarily require a much higher proportion of variable costs (primarily due to the cost of the fuel that is burned).

In order to arrive at a meaningful and useful distinction between costs that are capacity related and costs that are energy related, it is useful and necessary to recognize that some of the capital-related costs of building and owning a generating unit are better thought of as energy-related. Thus, the most useful and meaningful distinction that can be drawn between capacity-related costs and energy-related costs is not identical to the distinction between fixed costs and variable costs, nor is it identical to the distinction between capital-related and operating expense-related costs.

Act of 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980)).

Q. HOW DID YOU SPLIT FIXED COSTS BETWEEN THE ENERGY AND CAPACITY RELATED CATEGORIES?

A. I assumed the "capacity-related" portion of nuclear and combined cycle units are limited to the equivalent annual fixed cost of building and owning the combustion turbine. The remainder of the fixed costs of building and operating the nuclear plant and combined cycle plant are treated as part of the energy-related costs, rather than classifying them as capacity-related costs. This disaggregation of fixed costs is widely accepted – in fact, it is fundamental to the theoretical underpinnings of the peaker method.

The extra step involved in disaggregating fixed costs is particularly useful when examining the economics of a hydro or nuclear unit. In fact, the great majority of the capital investment in a hydro or nuclear plant is not attributable to the goal of meeting peak capacity (although hydro and nuclear plants also provide capacity that help achieve that goal). Rather, the bulk of the investment in a nuclear plant is attributable to the goal of safely producing energy with low fuel costs.

The water (and gravity) used to operate a hydro plant, and the uranium used to fuel a nuclear plant costs are less costly than coal, oil or natural gas – and this cost advantage is a key motivation for using these capital-intensive technologies. No one would invest in a nuclear unit just to provide capacity during peak hours. The added investment expended on baseload plants is only justified by the potential for minimizing fuel and other variable costs over the operating life of the plant. Consequently, any investment in excess of that required for a peaking plant is appropriately categorized as energy-related. The same logic applies to disaggregating the costs of the combined cycle plant, although the impact is not as significant.

After drawing this distinction, the levelized fixed annual cost estimates in 2017 dollars are summarized in the following table:

Cost per KW/Year	Nuclear	Combined Cycle	CT
Capacity Related	$ 82.36	$ 87.12	$ 87.12
Energy Related	565.60	48.86	0.00
Total[30]	$ 647.96	$ 131.23	$ 87.12

Q. ARE THERE ADDITIONAL COMPLICATIONS RELATED TO FLUCTUATIONS IN FUEL COSTS?

A. Yes. Aside from complications attributable to the existence of capital-related costs needed to produce electrical energy, the most important complication is the fact that future energy costs depend on the future level of fuel prices, which are volatile, and cannot be accurately predicted advance. In fact, because fuel prices are notoriously volatile, they are typically removed from the standard measures of inflation used by

30 The details of the calculations used in developing these cost estimates are discussed later, in the section of my testimony concerning capacity-related costs.

economists, stock market analysts, members of the Federal Reserve Board, and other knowledgeable observers when they are analyzing inflation.

The problem is especially acute with crude oil and natural gas prices. While these fuel sources have exhibited a tendency to trend higher and higher over the long term, they have also exhibited a tendency to fluctuate wildly over both short and medium time frames, making it very difficult to make optimal long-term investment decisions, or to anticipate the long term impact of any decisions related to energy usage. This is a problem that has been experienced by automobile manufacturers, airplane manufacturers, airlines and other firms that make long-term investments anticipating one level of energy prices, only to find those decisions to be sub-optimal (sometimes disastrously so) because energy prices ended up being different than they expected.

The problem with short term price instability was vividly illustrated as recently as 2016, when natural gas prices plunged by more than 20% during a few months early in the year, and then shot upward by nearly 40% over an even shorter time period later in the year.

In the following year, 2017, gas prices stabilized to some degree, albeit at very low levels by long term historical standards – in fact, the Wall Street Journal had a headline on the front page of its March 15, 2017 edition with the headline "Natural-Gas Glut Deepens." Prices subsequently bounced off the low of $2.88 experienced during March 2017, averaging $3.15 in May 2017, and thereafter fluctuating in a range from $2.82 to $2.98

during most of the year. The notable exception was November 2017 when milder than expected weather resulted in prices dropping to the low of the year – $2.01. Yet, two months later, in January 2018, unexpected cold weather led to gas prices shooting up to $3.87 – the highest prices observed since September 2014.

Recent improvements in gas drilling and extraction technology have led to an increase in supply relative to demand, which has contributed to unusually low prices by historic standards – averaging just $2.63 in 2015, $2.90 in 2016 and $2.90 in 2017. At these price levels, natural gas is so inexpensive it is displacing other options – especially coal and new nuclear plants. In some markets, low gas prices are even leading some observers to question the continued viability of maintaining and operating older nuclear plants. However, it would be a mistake to draw strong conclusions about the relative merits of different technologies solely on the basis of a few years of unusually low natural gas prices. To the contrary, gas prices have repeatedly experienced extreme fluctuations over multi-year periods.

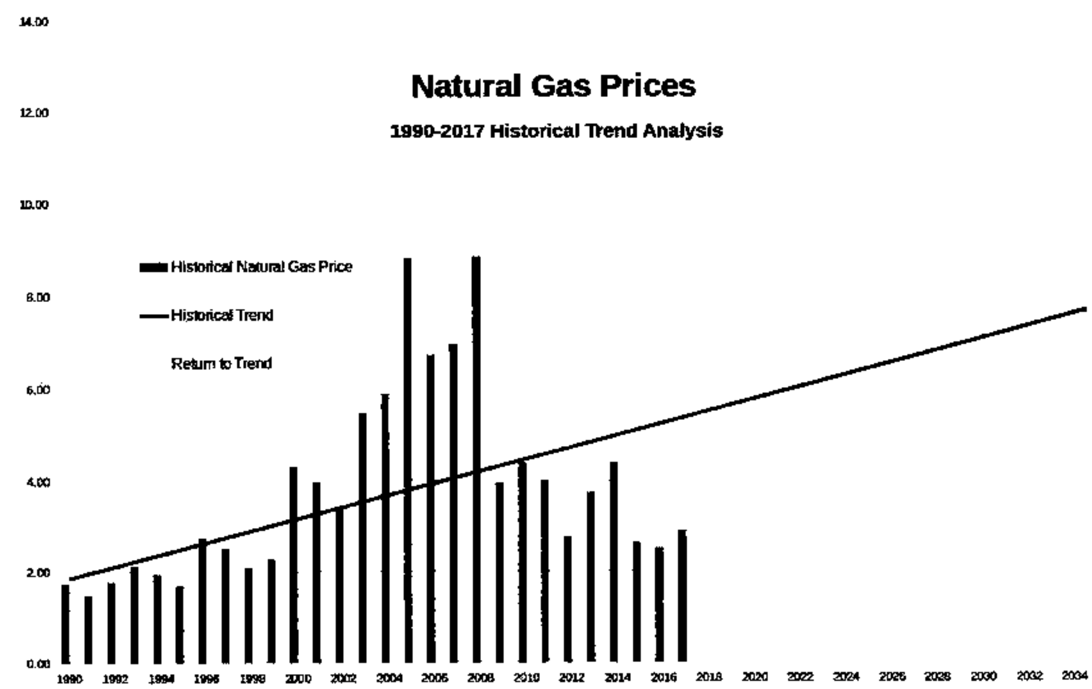
Generating plants are 30+ year investments, so the relative merits of each technology cannot meaningfully be evaluated strictly based upon current fuel prices. The decision to invest hundreds of millions of dollars in a new generating plant should be taken from a long term perspective, taking into account the risk that prices will change dramatically over the life cycle of the investment. In the case of a natural gas-fired generator, a significant risk exists that gas prices might suddenly double or triple, which would drastically change any conclusions one makes about the merits of the investment.

In fact, the instability of natural gas prices, and difficulties associated with predicting these prices for decades into the future is one of the principal disadvantages, or risks, associated with using this fuel source. These risks are important to keep in mind when evaluating the merits of long-term investments in gas-fueled generation relative to other options. Coal has some of the same risk characteristics as gas, but to a lesser degree, since coal prices tend to be more stable and because coal can be sometimes be purchased from coal mines pursuant to multi-year contracts at fixed prices.

The key point is that fuel price assumptions or projections are of critical importance when evaluating generating technologies or estimating energy costs using different fuel sources. In fact, the fuel cost assumptions will at least heavily influence, if not entirely determine, the conclusions that are drawn from an analysis of the relative cost-effectiveness of using different generating technologies.

Q. CAN YOU ELABORATE ON THESE PROBLEMS?

A. Yes. The following graph shows the long term upward trend in natural gas prices from 1990 through 2017. The light blue bars show average gas prices experienced during each of these years, using data obtained from Reuters (1990-96) and the Energy Information Administration (1997-2017). The dark blue line shows the linear trend reflected in that historical data, extended into the future. Finally, the pale yellow bars on the right side of the graph shows what future would look like, if gas prices were to smoothly return to the historical trend line and follow the slope of the historical trend line thereafter.



Given the wide fluctuations observed in the historical data (light blue bars), it is apparent that gas prices cannot be accurately predicted years in advance of when it is actually used. This uncertainty greatly complicates any attempt to analyze the cost of producing electricity using different fuels.

This problem is particularly acute when comparing the cost of generating sources that burn fossil fuels with those that don't. Simply stated, electricity produced with fossil fuels is subject to price risks that other technologies, including nuclear power, hydro, biomass, solar, geothermal and wind, are largely immune to. Any attempt to decide whether fossil fueled electricity is a higher or lower cost option for ratepayers will be almost entirely dependent upon your assumptions or projections concerning future fossil fuel prices.

This difference in risk characteristics is of vital importance when trying to analyze the impact on ratepayers of obtaining power from a QF at a guaranteed long-term fixed price, compared to the alternative of building a new generating plants that burns fossil fuel (or purchased power from a merchant plant that uses fossil fuel). The fossil fuel option is subject to significant pricing risk which are not applicable to technologies with low variable costs, like hydro and solar. Since fuel prices are subject to rapid change, and they not cannot be reliably predicted years in advance, this pricing uncertainty should be considered when attempting to evaluate the pros and cons of different generation sources. SCE&G considered this problem when evaluating its nuclear construction program, but it ignored the problem when evaluating appropriate price to pay QF's.

All else being equal, a customer will prefer a guaranteed fixed price to a mere estimate of what they might end up paying. To leave a customer indifferent between a renewable QF energy source at a guaranteed fixed price, and a fossil fuel source it is necessary to add a risk premium to the former option before attempting to draw any meaningful conclusions about which technology is preferable from a customer perspective. This is true regardless whether one is considering the construction of a new gas fired generator, purchasing electricity on the wholesale market at prices to be determined when the electricity is delivered, or by running one of the utility's existing generators – if the power comes from a fossil fuel source, the seller will almost never be willing to accept the pricing risk. Instead, the retail customer is forced to shoulder the burden of the pricing risk. This difference in risk is significant and should not be simply ignored.

Q. CAN YOU PROVIDE A REAL-WORLD EXAMPLE SHOWING HOW PRICING RISKS CAN BE DEALT WITH?

A. Yes. In its 2015 evaluation of the economic viability of its V.C. Summer nuclear construction project, SCE&G considered several different scenarios concerning potential future gas prices – all of which were higher than the unusually low prices that have recently been observed.[31] SCE&G started with

> two forecasts of natural gas prices at the Henry Hub. One is the current Energy Information Administration (EIA) natural gas forecast reported in their 2015 Annual Energy Outlook (AEO). The second is the proprietary natural gas forecast that SCE&G uses for planning purposes. To develop this forecast, SCE&G uses the forward prices reported for the NYMEX futures contracts over the next three years (i.e., through the end of 2018) and then applies an escalation factor … to forecast prices beyond three years in the future.[32]

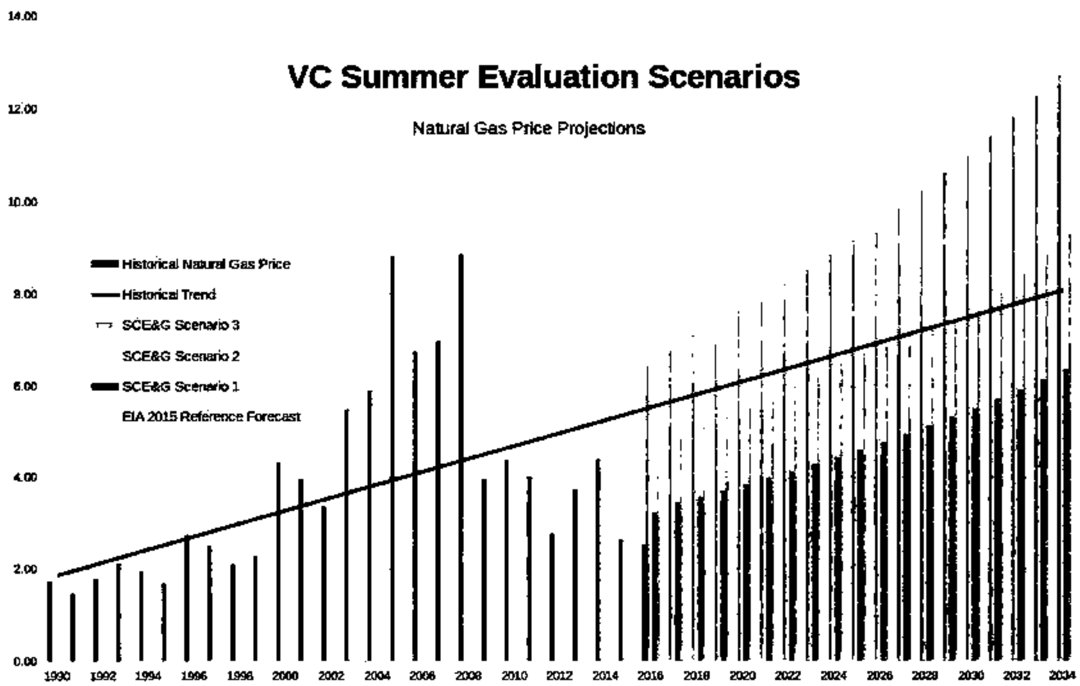
[31] South Carolina Electric & Gas, Comparative Economic Analysis of Completing Nuclear Construction or Pursuing a Natural Gas Resource Strategy, May 26, 2015.

[32] *Id.*, Page 3.

The latter forecast, which it described as its "base line forecast" of natural gas prices, was the lowest of three forecasts it developed and used for its evaluation. SCE&G also evaluated the impact of natural gas prices being 50% higher (Scenario 2) or 100% higher (Scenario 3) than this baseline.[33]

Recognizing that "all forecasts of future gas prices are subject to error" SCE&G looked at multiple scenarios, with their Baseline Scenario 1 forming the bottom of the range, Scenario 2 and the EIA's 2015 forecast falling in the middle, and Scenario 3 moving well above the others. Strictly speaking, Scenario 3 was not the highest pricing scenario SCE&G considered, since it also considered the impact of adding an estimate of the cost of carbon to natural gas prices.

33 *Id.*, Page 3.

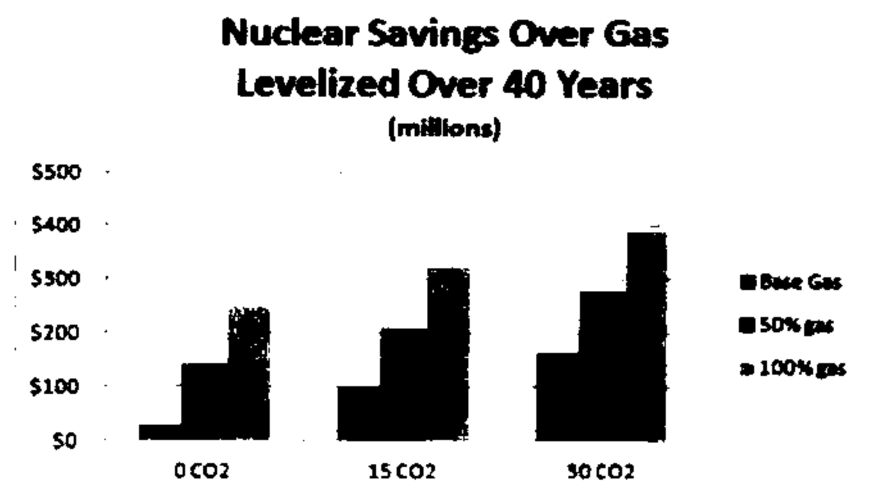


The three SCE&G scenarios are shown in the above graph, which also includes historical data and the historical trend line through 2016.

When reviewing this graph, it is important to keep in mind that the V.C. Summer evaluation was completed in June 2015, before most of the 2015 prices, or any of the 2016 prices were known.

The risks associated with higher natural gas prices were pivotal to the Company's conclusion in 2015 that it should continue to invest in construction of the nuclear units, despite the enormous sums required to complete them. This is clearly shown in this graph, which summarizes some key results of the study:[34]

CHART H



The group of three bars at the far left assumed no future government action penalizing or restricting carbon dioxide pollution. Absent any consideration of these environmental and political risks, continuing with nuclear construction was just barely superior to canceling the nuclear units and burning natural gas instead. This corresponds to the "Base Gas" pricing scenario (shown in blue at the far left) which was expected to result in $28 million of annual savings. This was a relatively small amount in the context of a risky, multi-billion dollar investment.

In its report, the Company interpreted these results as favoring continued construction of

[34] *Id.*, Page 8.

the units:

> This Chart highlights several critical points. First, completing the nuclear construction program is more economical than switching to a gas resource strategy across all scenarios modeled. In not one case is gas less costly than nuclear. The lowest level of nuclear advantage is a levelized annual advantage of approximately $28 million per year. This occurs using base gas price assumptions and CO2 prices at $0 per ton. In the 2008 Studies, the $0 per ton CO2 scenario with low gas prices resulted in nuclear being more costly than gas by $44 million.[35]

While not explicitly stated in the report, it was self-evident that, if gas prices turned out to be even a small amount <u>lower</u> than the Base Gas forecast, the natural gas option was going to be less costly than continued construction of the nuclear units. SCE&G had already spent $3 billion on the units at this point.[36] Although this past investment was being excluded from the analysis (on the theory that retail ratepayers were obligated to reimburse these costs regardless of whether or not the project was abandoned), billions of dollars of additional work still needed to be done. These "going forward" costs were the only ones being evaluated.

Given the inherent risks associated with nuclear construction, this going-forward investment only made sense if one believes the nuclear energy will ultimately save money compared to the energy it will displace. In turn, any conclusions about this tradeoff is necessarily a function of the assumptions one makes about future fossil fuel

35 *Id.*

36 *Id.*, Page 3.

costs and risks. The Company fully understood the significance of these uncertainties and risks, as indicated by this passage in the report:

> ...the study shows that the comparative economics of the nuclear and natural gas resource strategies swing widely based on gas price forecasts and future CO2 cost assumptions. This shows that the economics of the gas resource strategy are very sensitive to swings in natural gas prices and CO2 costs. This confirms that a resource strategy dependent of natural gas generation significantly increases SCE&G's exposure to fossil-fuel volatility and environmental cost increases.[37]

In fact, the decision whether to abandon the project or go forward with construction was almost entirely dependent on what level of fuel costs were estimated to occur over the 60 or more years, and how the risks associated with that estimate. A net present value difference of $28 million per year was clearly not a sufficient basis for continuing to incur the nuclear scheduling, regulatory, and cost risks, unless those risks were outweighed by the risk of sharply higher fossil fuel costs at some point during the useful life of the plant.

The trade-off between construction risks and fuel price risks is one that has long been understood by utilities – since the industry has frequently encountered difficulties constructing new nuclear units on schedule or at the originally estimated cost. Problems with schedule delays and construction cost over-runs are risks that have been widely recognized since the late 1980's, as indicated by the many proposals that have been

[37] Id., Page 9.

offered since that time with respect to reforming nuclear regulation and nuclear construction practices, in an effort to make nuclear power a less risky, more cost effective alternative to fossil fuels.[38]

Q. WERE ANY OTHER RISKS CONSIDERED BY SCE&G IN EVALUATING WHETHER TO CONTINUE WITH CONSTRUCTION OF THE NUCLEAR UNITS?

A. Yes. The primary other rationale offered by SCE&G was the potential benefit of achieving a more "balanced" generating portfolio – one that avoided placing excessive reliance on fossil fuels. A more "balanced" portfolio of generating resources would provide better protection from the environmental and legal risks associated with being heavily reliant on fossil fuels – risks which apply to both coal and natural gas. The Company quantified some of the associated environmental and political risks by studying alternative scenarios in which a "price of carbon" would eventually be imposed on

[38] See for example: E. Ray Canterbery, Ph.D, Don Reading, Ph.D, and Ben Johnson, Ph.D, "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." Southern Economic Journal, January 1996.

burning fossil fuels. These risks (and associated scenarios) were reflected in the use of multiple rows this chart:

CHART I
Base Load Scenario

Benefit of Nuclear Strategy over the Gas Strategy Levelized Present Worth of Change in Revenue Requirements Over 40 Years ($MM)			
	Base Gas	50% Higher Gas	100% Higher Gas
$0 CO2 Price	$28	$144	$248
$15 CO2 Price	$97	$210	$326
$30 CO2 Price	$166	$278	$392

In effect, the environmental and political risks associated with fossil fuels were quantified by evaluating scenarios which included a "price of carbon" of $15 or $50 per ton. These risks (together with the fuel price risks discussed earlier) were the underlying basis for why the Company felt it was important to avoid excessive reliance on fossil fuels. The logical connection is clearly reflected in this passage:

> A significant advantage of continuing construction of the two nuclear units is that once added to SCE&G's generation fleet, the Units will produce a well-balanced capacity portfolio. The following charts show the percent distribution of capacity under a plan of continuing nuclear construction and the alternative of replacing it with natural gas fired capacity.

CHART A

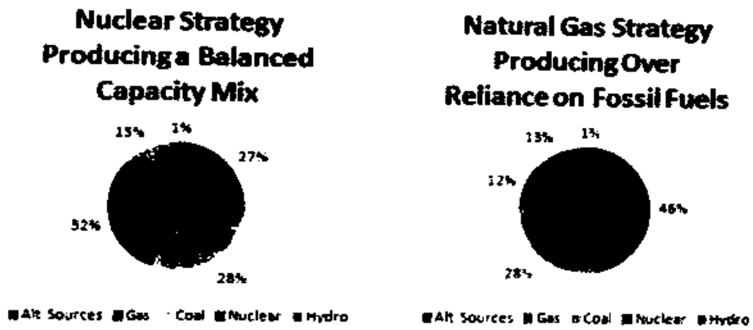


Chart A shows that the Natural Gas Strategy produces a generation system that in 2021 relies on fossil fuels for 73% of its generating capacity. The Nuclear Strategy creates a more balanced portfolio. Such a portfolio better protects customers from unexpectedly high costs in any one fuel source while allowing the utility to take advantage of opportunities in others.

Q. IN DEVELOPING ITS PROPOSED QF RATES IN THIS PROCEEDING, DID THE COMPANY EVALUATE THE BENEFITS OF A BALANCED GENERATING PORTFOLIO?

A. No. In developing its avoided cost estimates and its proposed QF tariffs, SCE&G ignored the potential benefits of achieving a more balanced generating portfolio as it increases the amount of QF power it purchases.

Q. DID SCE&G USE MULTIPLE SCENARIOS TO COMPARE THE RISKS OF FOSSIL FUELS TO THE RISKS OF QF POWER?

A. No. I've seen no indication that SCE&G evaluated the impact of different future trajectories in fuel prices, nor did I see any indication it gave any consideration to the environmental and political risks associated with excessive reliance on fossil fuels. More specifically, I saw no evidence it used multiple fuel price scenarios to develop its "Base" expansion plan, nor did I see any evidence it systematically evaluated the impact of these risks in the context of any of its DRR "Change" scenarios.

This is not due to any limitation in the Commission-approved Differential in Revenue Requirements methodology. The DRR method is fully capable of evaluating these types of risks, assuming appropriate inputs and assumptions are used. All the Company needed to do was to analyze multiple different generation expansion plans, and then run PROSYM using multiple input scenarios corresponding to different risk scenarios (e.g. different fuel cost levels and carbon prices).

Had the DRR method been implemented in this manner, the Company could have provided the Commission with better, more useful information concerning the QF-related issues in this proceeding. It could have shown the Commission how the Company's Revenue Requirements will differ depending on the level of fuel prices which occur in the future, and how the previously mentioned political and environmental risks play out. By failing to evaluate multiple scenarios, the Commission lost the ability to evaluate the risks and that will be borne by ratepayers if adopts policies that discourage competitive QF investment in renewable energy, and favor monopoly investment in fossil fuels.

In this proceeding SCE&G apparently just ignored the benefits of a more balanced generating portfolio. The failure to consider these risk differences is such a serious error that it is a sufficient basis, in and of itself, for rejecting the Company's proposed QF tariff revisions. Furthermore, the extreme inconsistency between the approach used in this proceeding and the one used in evaluating the nuclear construction program calls into question the Company's credibility. If it were concerned about maintaining its credibility, objectivity and consistency, the Company would at least have made sure to study the same risks it focused on when deciding to continue with building the nuclear units.

Q. CAN YOU BE MORE SPECIFIC IN EXPLAINING HOW FOSSIL FUEL RISKS COULD HAVE BEEN STUDIED IN THIS PROCEEDING?

A. Yes. Under the DRR method, "Base" and "Change" expansion plans are compared.

> As approved by the Commission in Order No. 2016-297, SCE&G uses a difference in revenue requirements methodology to calculate both the energy component and the capacity component of its avoided costs. … The base case is defined by SCE&G's existing fleet of generators and the hourly load profile to be supplied by these generators. The change case is the same as the base case except that the hourly loads are reduced by a 100 MW profile, which is the maximum reduction required by PURPA regulation 18 C.F.R. § 292.302(b)(1) for utilities with systems larger than 1,000 MW of generation such as SCE&G. Direct Testimony of Joseph M. Lynch Docket No. 2018-2-E, Page 4.

This description is largely accurate, although somewhat misleading.[39] In particular, the Company's "base case" was not limited to the "existing fleet of generators." The "base case" also includes expected additions of new QF solar capacity, as well as two new combined cycle plants. These expected changes to the existing generating fleet were not disclosed by Dr. Lynch in his testimony, but they were included in every potential version of the Company's "Base" expansion plan.[40]

However the assumptions (which understate the amount of solar capacity that will be coming onto the grid) were however explained in the Company's 2018 Integrated Resource Plan.

> SCE&G's resource plan for the next 15 years is shown in the table labeled "SCE&G Forecast Summer and Winter Loads and Resources – 2018" … line 7 the resource plan shows the amount of firm solar capacity expected to be added to serve the system summer peak. As shown on line 5, by 2020 this solar capacity accumulates to 865 MWs of solar capacity but only 35% of this capacity is assumed firm and therefore reflected in the resource plan.[41]

To be clear, in developing its Base expansion plan, the Company did study several different investment strategies or scenarios. For instance, it tested the impact of varying the timing of new rate base investments, and it experimented with different combinations

[39] It is worth noting that 100 MW is actually the maximum reduction allowed under PURPA, rather than being a requirement. Utilities are free to use a smaller increment in estimating avoided costs.

[40] See the tab "Expansion" at cells K14 through K24 in: EPLAN17_Summer-Winter_CC2023_(112017).xlsx,

[41] SCE&G 2018 Integrated Resource Plan, page 40.

of combined cycle units and combustion turbines.

However, I saw no evidence that any of these strategies were evaluated using multiple fuel price scenarios. I also noticed that all of the strategies assumed acquisition of the Columbia Energy Center (part of the Dominion merger proposal) would be approved. No evaluation was made to determine the optimal expansion plan if the proposed acquisition of the Columbia Energy Center, or the proposed Dominion merger, were rejected. Furthermore, there was very little testing of the impact of engaging in firm energy purchases, rather than adding more generating units to the Company's rate base.

More potential expansion strategies should have been considered, and all of the strategies should have been "stress tested" or evaluated using several different sets of assumptions, particularly with respect to different fuel price scenarios. The optimization process used to select the "Base" expansion plan should have clearly demonstrated that the selected expansion plan had the lowest expected revenue requirement, after adjusting for differences in risk.

Q. CAN YOU GIVE A SPECIFIC EXAMPLE OF SCENARIOS THAT SHOULD HAVE BEEN STUDIED WITHIN THE DRR ANALYSIS, BUT WERE NOT?

A. Yes. I saw no evidence the Company gave any consideration to the tradeoffs between rate base investments and wholesale power market transactions, much less sought to achieve an optimal mix of rate base investments and power purchases. Yet, in past proceedings the Company used purchased power contracts to help minimize its revenue requirement, and provide added flexibility with respect to the timing of when the nuclear units would be completed.

In this proceeding the Company is attempting to modify its Base expansion plan, rather than using the same one that was used in last year's QF filing. It not only removed the nuclear units, but it developed a new expansion plan that replaces those units with fossil fuel generating plants owned by Company. To help minimize the revenue requirement, it should have studied the effect of using firm purchased power contracts accommodate an optimal portion of the energy and capacity needs that were previously being met by the nuclear units. Without evaluating the purchased power option, there is no valid basis for arguing or assuming that the new "Base" expansion plan is appropriate for use in the DRR method. The problem is that lacking any use of purchased power contracts (particularly the purchase of firm blocks of energy only during peak hours, when energy is most needed), it failed to confirm whether the newly defined "Base" expansion plan minimizes the revenue requirement. In turn, without properly minimizing revenue requirements in the "Base" case, any comparisons that are made to the QF-related "Change" case will not be consistent with one of the most foundational requirements of the DRR method.

In considering this concern, the Commission should keep in mind that evaluating the pros and cons of investing in new capacity or purchasing output from another firm is